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CEDAR CREEK DAM HYDROELECTRIC PROJECT FEASIBILITY STUDY

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CEDAR CREEK DAM HYDROELECTRIC PROJECT
FEASIBILITY STUDY

Prepared by

City of Columbia Falls
Drawer G
Columbia Falls, Montana 59912

October 1983

Prepared for

Montana Department of Natural Resources and Conservation
1520 East 6th Avenue, Helena, Montana 59620
Renewable Energy and Conservation Program
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PROJECT SUMMARY

Under grant Milestone No. 9, this report outlines and summarizes the work performed in the feasibility study of the Cedar Creek Dam Hydroelectric Project. During the course of this project, grant Milestones No. 2, 3, and 4 were completed. In Milestone No. 4, project design and cost estimation reached the stage of their development where project economic feasibility could be assessed on a simple cost-per-kilowatt-hour generated basis. This analysis yielded a figure of 187 mills per kilowatt-hour, indicating that the project was not feasible and that further study should be terminated. This high unit energy cost can be attributed to the following:

- The small annual energy production available at this site, where the season during which discharge is available is limited and where available head is limited by existing facilities and modes of operation.

- The high cost of generating equipment with respect to the small available energy potential of the site and the sizeable cost incurred where adequate three-phase power transmission facilities are not present at or very near the site.

This report summarizes each phase of project work performed: data collection and analysis, power generation and marketing analysis, project preliminary design, equipment selection, cost estimation, and feasibility evaluation. Appendices following the text contain supporting information for each phase of work.

MILESTONE NO. 2: DATA COLLECTION

Feasibility study work under the grant began with the collection of project data. This process had, in fact, begun before the study grant was awarded, consisting of field reconnaissance surveys by consultants. These were performed in November 1980 by J. M. Montgomery, Consulting Engineers, Inc.; and in February 1981 by CH2M HILL. Under the grant, information was collected on site hydrology, water rights and legal status, the local power distribution system, site conditions (via field investigations), and existing facilities. The subsections that follow briefly summarize each type of data and its sources. The actual data are contained in the appendices of the Milestone No. 2 report prepared in December 1982. Excerpts from these appendices are included in Appendix A of this report, as noted.

HYDROLOGIC

Data included U.S. Soil Conservation Service (SCS) publications Hydrology of Mountain Watersheds and Average Annual Precipitation - Montana, U.S. Geological Survey (USGS) gage information and duration tables for 11 local or similar streams, actual site flow measurements taken in 1972 by the SCS and in 1982 by the City, and a USGS topographic map of the site area. The map is included in Appendix A of this report.

LEGAL AND WATER RIGHTS

This portion of the report included a water rights summary, partial copies of Plat 27-31-20 and Plat 34-31-20 (wherein the dam and reservoir are located), and a copy of the deed from Anaconda Aluminum Company granting two tracts in Section 34 to the City of Columbia Falls for the dam site, all

supplied by James A. Cumming, attorney for the City of Columbia Falls. Although a minor dispute regarding presently held water rights was yet to be resolved, no obstacles existed which would prevent the City from obtaining necessary rights for the project.

POWER SYSTEM

Data included maps and description of the electric distribution system with which the proposed power plant would be interconnected (supplied by the Pacific Power and Light Company [PP&L], Kalispell office) and a copy of the PP&L "Purchases from Cogenerators and Small Power Producers" rate schedule, Schedule No. 87, issued June 29, 1982. A description of the route of the distribution line that now serves Cedar Creek Dam is provided in Appendix A of this report.

FIELD INVESTIGATIONS

This information consisted of copies of reports generated by past and recent field assessments of the proposed site. These included a November 1980 letter report by J. M. Montgomery, Consulting Engineers, Inc.; the October 1980 National Dam Safety Program Inspection Report (Dam MT-1455); and an August 1982 CH2M HILL field report. The dam safety report did not indicate any serious weaknesses in existing structures and the field survey reports concluded that the site might be amenable to hydropower development.

EXISTING FACILITIES

This information included the SCS Cedar Creek Dam as-built construction drawings and a copy of an SCS letter outlining the proper operation of the project's flood control measures (originals are on file with the SCS in Bozeman, Montana).

MILESTONE NO. 3: POWER PRODUCTION AND MARKETING

The report related to this task was prepared in January 1983 and presented an analysis of potential power production and potential power markets. Excerpts are included in Appendix B of this report, as noted.

POTENTIAL POWER PRODUCTION

Available Discharge

Records of available discharge at the proposed site were very limited. The only available data were daily releases recorded during portions of 1972 and 1982 by the SCS and the City of Columbia Falls, respectively. These measurements were made by use of a Parshall flume in the diversion channel below the dam. The figures represent discharge available in excess of that necessary to meet the City's municipal water needs. They are plotted in Figure 1, Appendix B, of this report.

An estimated flow duration curve was developed for Cedar Creek at the proposed site by means of correlation with other similar streams on the basis of drainage area. Seven of the streams identified in the Milestone No. 2 report were analyzed because of their similarity to Cedar Creek in elevation, precipitation, and orientation. None were regulated. The estimated flow duration curve for Cedar Creek was developed by the following procedure:

1. Flow duration values for each of the seven available streams were obtained (see Appendix A, Milestone No. 2 report) and unitized by dividing the values by each stream's average annual discharge (see Table 1, Appendix B, of this report).

2. These unit duration values were then plotted versus drainage area for each stream to form a family of curves with different exceedance percentages (see Figure 2, Appendix B, of this report).

3. Figure 2 was entered with the drainage area of Cedar Creek above the dam, and unit flows at the various exceedance percentages were obtained for Cedar Creek (see Table 1, Appendix B).

4. Average annual flow for Cedar Creek was estimated from the data for Canyon Creek on the basis of the ratio of their drainage areas. Canyon Creek was selected because of its particular similarity to Cedar Creek in drainage area, situation, and exposure (see Table 1, Appendix B).

5. The unit duration curve obtained in Step 3 above was then multiplied by the average annual flow value obtained in Step 4 to produce an estimated flow duration curve for Cedar Creek (see Figure 3, Appendix B, of this report).

By inspection, it could be seen that the resulting site flow duration curve was generally consistent with the 1972 and 1982 release hydrographs shown on Figure 1 (Appendix B). This suggested that the assumption of correlation between Cedar Creek and the seven analyzed streams was a reasonable one for this feasibility-level investigation. No adjustment to the flow duration curve was made for municipal water demand because of its insignificant peak value--less than 5 cubic feet per second (cfs)--and the underlying level of accuracy of the estimated site discharge.

On the basis of the hydrographs and flow duration curve, a hypothetical two-unit power plant with a maximum hydraulic capacity of about 40 cfs was proposed for the power and energy estimates of this milestone. It would operate 2 to 3 months per year.

Available Head

From the standpoint of operating head, the most conservative assumption of project configuration was as follows:

1. Maximum reservoir water surface elevation would be limited to slightly above the crest of the operating spillway; say, elevation 3227 feet.

2. No modification of existing project facilities would be permitted; that is, no raising of the operating spillway crest by extending the riser and no relining or utilization of the existing outlet conduit. Either could affect the dam's safety and ability to pass floods. As a result, hydropower facilities would probably consist of a siphon which would extend from an inlet located below the operating spillway crest elevation through the dam's crest to a power plant located near the dam's toe.

3. Releases could not be made to the natural stream channel, but must continue to be discharged into the existing diversion channel at the toe of the dam. As a result, a power plant's tailwater elevation at 40 cfs would be about 3192 feet.

The above assumptions resulted in a gross available head of 3227 - 3192 = 35 feet. Maximum gross head was, therefore,

something greater than 35 feet under zero-discharge conditions. Although reservoir levels decrease to well below the operating spillway crest during the year, they would typically be in that vicinity during the "generating season." As a result, the average gross head would be essentially equal to the maximum value.

At 40 cfs, 30-inch penstock friction and minor losses would amount to about 3 feet. The resulting net operating head was thus estimated to be 32 feet.

Potential Installed Capacity

On the basis of a full-gate discharge of 40 cfs and an associated net operating head of 32 feet, the plant's installed capacity would be given by:

$$\text{Installed Capacity} = \frac{QHe}{11.82} \text{ in kilowatts (kW)}$$

Where

Q = 40 cfs

H = 32 feet

e = 0.80 overall efficiency

The computed value was 87 kW.

Enhancement of Power Production

The only economical method by which power production could have been increased at this site would have been by increasing available head. Two basic possibilities existed for accomplishing this:

1. Increase reservoir operating level. All of the measures considered involved spillway and/or pool level modifications and could detract from the ability of the existing dam to safely pass floods. They would, therefore, require considerable investigation and perhaps major modifications to the dam.

2. Decrease power plant tailwater elevation. If releases could be made to the natural channel of Cedar Creek, a tailwater elevation of as low as 3185 feet (at 40 cfs) could be achieved.

By increasing the reservoir operating level to 3236 feet alone, net operating head could have been increased to 41 feet and potential installed capacity would have increased to 111 kW. Because raising the reservoir level would probably require major dam modifications, this alternative was judged not likely to be economically feasible.

By decreasing the plant tailwater elevation to 3185 feet alone (and increasing head losses slightly because of a longer penstock), net head could have been increased to 38 feet and potential installed capacity would have increase to 103 kW. If both measures were adopted, net head would have increased to 47 feet and potential installed capacity would have been increased to 127 kW.

POWER MARKETING

The market for power produced by a project such as the proposed one has essentially been established by two pieces of recent legislation: the Public Utility Regulatory Policies Act (PURPA) and the Pacific Northwest Electric Power Planning and Conservation Act. Basic requirements for

interfacing small hydro systems with a utility transmission grid have been established by the Montana Public Service Commission (March 1982) in conformance with PURPA. Subsequently, each utility has developed its own set of guidelines and requirements for small hydro developers wishing to enter into a power sales agreement.

PP&L serves the Cedar Creek Dam site north out of the City of Columbia Falls. Thus, from the standpoint of project cost, PP&L was the only practical market for power produced by the project. Initial contact was made with PP&L through its Kalispell District and Portland, Oregon corporate offices. Interest in the project's generation was expressed by the Renewable Energy Department in the Portland office. PP&L Rate Schedule No. 87, which describes rates payable for power purchases from cogenerators and small power producers, was obtained. A copy of a power purchase agreement was also obtained. Copies of both were included in the Milestone No. 3 report.

MILESTONE NO. 4: EQUIPMENT SELECTION, PRELIMINARY DESIGN, AND PROJECT FEASIBILITY

This task included determination of the project configuration, equipment selection, preliminary design, estimation of energy production and project cost, and evaluation of feasibility. The latter analysis indicated that the proposed project was not economically feasible. Pursuant to grant Milestone No. 1, notification of this conclusion was given to the Montana Department of Natural Resources and Conservation. Upon the department's concurrence, preparation of this final report commenced. The Milestone No. 4 report itself was prepared in April 1983. Excerpts are provided in Appendix C of this report, as noted.

PROJECT CONFIGURATION

Selection

Cedar Creek Dam was constructed in 1971 by the SCS to provide both municipal water supply and flood protection for the City of Columbia Falls. Flood protection is provided by retention storage in the reservoir and by the diversion of releases via an operating spillway into a channel which conveys them to an outfall on the Flathead River east of Columbia Falls. Thus, flows in the natural channel of Cedar Creek downstream of the project are kept to a minimum. The dam also has an emergency spillway, but any significant discharge would seriously erode its channel and also cause a washout of the above diversion channel where the spillway discharge is allowed to return to the natural channel of Cedar Creek. Under these conditions, the dam structure would be protected, but the intended downstream flood control function would be impaired.

The possible alternative configurations for a hydropower addition at Cedar Creek Dam differed primarily in their method of conveying water to the power plant and in the amount of operating head they would develop. The energy production potential of this site was not such that the expense of major redesign or construction efforts, such as dam modifications, could be economically justified. In addition, any modifications which violated SCS design criteria or otherwise negatively impacted the dam's safety or intended purposes would violate the operation and maintenance agreement between the SCS and the City. These considerations formed the criteria by which alternative project configurations were evaluated at the feasibility level.

Two alternative methods for conveying water to a power plant were considered practical:

1. Relining the existing operating spillway conduit and adding a branch to its downstream end whereby its discharge could be diverted to a power plant or to the existing impact basin.

2. Maintaining the existing configuration of the operating spillway while delivering available discharge to a power plant by means of a siphon arrangement.

SCS design criteria dictated that Alternative No. 1 would not be acceptable because its effect would be that the existing facilities could no longer be considered an operating "spillway." On the other hand, if properly constructed, the siphon configuration would not affect existing operation or dam safety.

Assuming a siphon configuration, various possibilities existed for increasing plant operating head. Three of the most straightforward approaches were:

1. To raise the operating level of the reservoir by raising the elevation of the operating spillway crest (extend the riser).

2. To raise the operating level of the reservoir by controlling releases through the existing operating spillway (by addition of a valve).

3. To lower the power plant's tailwater elevation by discharging to the natural stream channel rather than to the dam's diversion channel.

However, approaches No. 1 and No. 2 were unacceptable to the SCS because either would compromise the dam's safety and would result in a higher frequency of emergency spillway operation. Likewise, any increased discharge to the natural stream channel would impair the flood control purpose of the project; therefore, the third approach was also deemed unacceptable.

Description

On the basis of the above considerations, no changes in headwater or tailwater elevations could be recommended. In order to preserve the intended mode of operation of the operating spillway, a siphon arrangement was proposed to convey water to a power plant discharging into the existing diversion channel. Figure 1 in Appendix C shows the proposed project layout in plan. Figure 2 in Appendix C shows the proposed profile for the intake, siphon penstock, power plant, and tailrace. As noted in the Milestone No. 3 report, a plant design discharge (Q) of 40 cfs was proposed.

This value fell slightly above the 20 percent exceedance value of the estimated flow duration curve. On the basis of experience and the hydrographs presented in the Milestone No. 3 report, it was decided that such a design capacity should maximize energy production during most years.

A nominal penstock diameter of 30 inches was selected to limit flow velocity at design Q to less than 10 feet per second (fps). The penstock invert elevation at the siphon crown is 3235 feet in order to limit maximum negative pressures at the crown to less than 10 feet (4.3 psi). Concrete thrust anchors and seepage collars would be installed on the penstock as necessary. The siphon would include upstream and downstream isolation valves as well as vent and fill taps accessible on the dam's crest as shown. The tailrace would consist of a riprapped earthfill channel extending from the turbine discharge to the existing diversion channel as shown on Figures 1 and 2 (Appendix C). Figure 3 in Appendix C shows the plan and section views of the proposed intake structure, including the upstream isolation valve. The isolation valve stem would be supported at intervals along the penstock to a handwheel operator mounted on the upper thrust anchor.

The power plant would consist of a reinforced concrete structure for mounting the turbine(s), generator(s), and their accessories at the toe of the dam. The equipment would be protected from the elements by a pre-fab metal enclosure. The downstream siphon isolation valve would be spring-loaded and normally closed in order to automatically isolate the penstock (and therefore maintain siphon priming) during power plant shutdown.

Mode of Operation

During the generating season (April, May, and June of most years), available discharge would increase to a level which

could be efficiently utilized for hydropower generation. The reservoir level would be above the operating spillway crest. At this time, plant operation would begin by priming the siphon. The siphon and turbine-generator(s) could then be started by opening the downstream isolation valve at the power plant. Plant interconnection and startup would proceed in a manner typical of induction machine applications (motor starting, then load pickup).

The plant would normally run unattended. Shutdown would be automatic for the various electrical/hydraulic protection conditions, with manual restart. When available discharge decreased to below the plant's minimum capacity, reservoir drawdown would actuate a float switch mounted on the operating spillway riser and cause plant shutdown.

UNIT SELECTION

The selection of suitable turbine and generator units for this project was a technical and economic decision based upon site head/discharge characteristics and an evaluation of equipment manufacturer proposals.

Site Characteristics

Figure 4 in Appendix C shows curves which relate plant tailwater elevation, penstock and intake head losses, and available net head to plant discharge. These curves were based on the following:

1. During the April-June generating season, the reservoir operating level was assumed to be 3226.5 feet. This is the operating spillway crest elevation.

2. The diversion channel invert elevation in the vicinity of the proposed tailrace channel is approximately 3190 feet. The depth of flow in the diversion channel was estimated to range from 0 to 2 feet as discharge ranged from 0 to 40 cfs. Assuming a tailrace channel whose hydraulics were similar to the diversion channel, plant tailwater would vary from 3190 to about 3192 feet over this range of discharge.

3. Head losses were estimated as follows:

   a. Trashrack: 1.0 H_V under 50 percent net area conditions.

   $$1.0\ H_V = (1.0)\left(\frac{1}{2g}\right)\left(\frac{1}{20^2}\right)\ Q^2 = 3.88 \times 10^{-5}\ Q^2$$

   b. Entrance: 1.0 H_V, conduit area basis.

   $$1.0\ H_V = (1.0)\left(\frac{1}{2g}\right)\left(\frac{1}{4.59^2}\right)\ Q^2 = 7.38 \times 10^{-4} Q^2$$

   c. Conduit friction head loss by Manning's equation:

   L = 200 feet
   I.D. = 2.42 feet
   Welded steel: n = 0.012

   $$(6.68 \times 10^{-4})\left(\frac{L}{ID^{16/3}}\right)\ Q^2 = 1.21 \times 10^{-3} Q^2$$

   d. Minor losses:

   Four bends (1 @ 22°, 3 ° 27°): $0.2H_V$ total

   Two 30-inch butterfly valves: 0.4 H_V total

$$(0.2 + 0.4)\left(\frac{1}{2g}\right)\left(\frac{1}{4.59^2}\right) Q^2 = 4.43 \times 10^{-4} Q^2$$

Total head loss = $2.43 \times 10^{-3} Q^2$ in feet where Q is plant discharge in cfs.

Available net head at a given discharge was 3226.5 feet minus the tailwater elevation and head loss at that discharge.

The plant design point was thus

Design Discharge = 40 cfs

Design Head = 31 feet

These characteristics suggested turbine(s) with a high specific speed and, therefore, predominantly axial flow.

Evaluation of Equipment Proposals

Requests for proposals (RFP's) for equipment packages were sent to turbine-generator manufacturers. Each RFP presented the project description and design data as developed herein and requested a proposal which would outline equipment characteristics and costs. Suppliers were selected to provide a broad range of sophistication and cost of equipment upon which alternatives could be based.

Copies of the RFP's and manufacturer responses were included in the Milestone No. 4 report. Table 1 in Appendix C presents a comparison of the salient points of the four equipment alternatives.

Estimated Energy Production

Project energy production was analyzed according to the power duration curve method. This approach involves the

analysis of a power duration curve which has been computed from the flow duration curve, net head vs. discharge curve, and equipment performance data. The area under the power duration curve between the plant operating limits is equal to the annual energy production.

Plant performance was estimated in terms of plant overall efficiency over the turbine operating range for each of the alternative equipment packages. The plant efficiency versus discharge relationships are tabulated in the power duration analysis presented in Table 2, Appendix C. For Alternatives No. 1 and No. 2, these values were based upon typical turbine performance curve shape and the peak efficiency value provided by each supplier.

For the values of discharge on the flow duration curve within each alternative turbine's operating range, net head was estimated and a plant output was computed and plotted versus percent exceedance. The resulting power duration curves are shown in Figure 5, Appendix C. The area in kilowatt-hours (kWh) under each curve was then computed. These values are tabulated in Figure 5, Appendix C.

PROJECT EVALUATION

In order to select the most economical project design and verify project feasibility, a preliminary evaluation of project economics was made. The project alternatives differed in their power plant equipment package and energy production. A comparison of the alternatives was made on a cost per kWh generated basis in order to select the most economical approach. This most economical project energy cost was then compared with estimated revenue to assess overall project feasibility.

Project Costs

The major components of the proposed project were: the siphon intake, the penstock, the power plant equipment package, the powerhouse structure and enclosure, and the power transmission line. Project power transmission facilities would consist of three-phase electrical cable necessary to make the connection between the plant circuit breaker and the secondary terminals of a padmount transformer provided by PP&L. Also included were modifications of the existing PP&L transmission system necessary to accommodate interconnection.

In terms of cost, the proposed project alternatives differed mainly with respect to the power plant equipment package. In the case of each, the total estimated costs are summarized in Table 3, Appendix C. A contingency of $30,000 (about 15 percent) was added to account for omitted items and other unforeseen costs. The total 1983 project costs included engineering and administration to cover design, licensing, and construction management.

These cost estimates were prepared for guidance in project evaluation and implementation from the information available at the time of the estimate. The final costs of the project would depend on actual labor and material costs, competitive market conditions, final project scope, implementation schedule, and other variable factors. As a result, the final project costs would vary from the estimates presented.

Feasibility

The selection of the recommended alternative was made on the basis of minimum cost-per-kWh-generated. Annual costs for

each alternative were estimated on the basis of the following assumptions:

- The useful life of each alternative would be 30 years (optimistic for Alternatives No. 2, No. 3A, and No. 3B).

- Both alternative selection and feasibility evaluation would be performed on the basis of 1983 costs and current utility rate schedules in order to make valid comparisons. In reality, project costs and financing would have to take into account the escalation in project costs until construction was actually funded (1984 at the earliest). A power purchase agreement would be based upon rate schedules in effect when the project came on-line (1985).

- Long-term project financing would be for a period of 30 years at an interest rate of 10 percent.

- The nominal annual cost of plant operation and maintenance would be $5,000 ($7,000 for the single-unit and $10,000 for the three-unit schemes of Alternative No. 3 due to the use of off-the-shelf pumps).

- All other administrative and miscellaneous costs were neglected.

The estimated annual cost and cost-per-kWh generated for each alternative are shown in Table 3, Appendix C. The unit energy cost for the three-unit Idaho Pump Supply alternative was lowest at 187 mills per kWh. This alternative would produce the least costly energy.

An evaluation of the economic viability of the recommended alternative was also made. This was accomplished by comparing the project annual cost with estimated revenues payable by PP&L under its current Rate Schedule No. 87 (see Milestone No. 3 report).

The following assumptions governed the calculation of annual power revenues:

- The power sales contract would be for a period of greater than 4 years ("long-term rate").

- Energy and capacity payments would be made on the "average rate" basis because the project would have no peaking capability.

- Capacity payments would be made on the basis of a demonstrated capacity factor (dcf) of

  $$dfc = \frac{\text{Annual Energy Production}}{\text{Maximum Output in kW x 8,760 hours}}$$

  Where Annual Energy Production = 216,700 kWh (Table 3, Appendix C)

  Maximum Output = 76 kW (Table 1, Appendix C)

  dcf = 0.33

  This method of dcf calculation is described on Page 2 of the PP&L Power Purchase Agreement included in the Milestone No. 3 report.

- The power plant would operate continuously during the generating season.

Annual power revenues for the recommended alternative were:

Energy Payment = (216,700 kWh)($0.0499)
= $10,813 per year

Capacity Payment = (12 months)($7.21)(76 kW)(0.33 dcf)
= $2,170 per year

Total Annual Revenue = $10,813 + $2,170
= $12,983

From Table 3, Appendix C, the estimated annual cost was $40,540. Therefore, the project would initially suffer an annual loss of about $27,557. This result coincided with the prohibitively high energy costs calculated in Table 3 (Appendix C) and yielded the same conclusion: the proposed project was not economically feasible. The primary reason was the small annual energy production relative to the size and cost of the facilities required to generate power.

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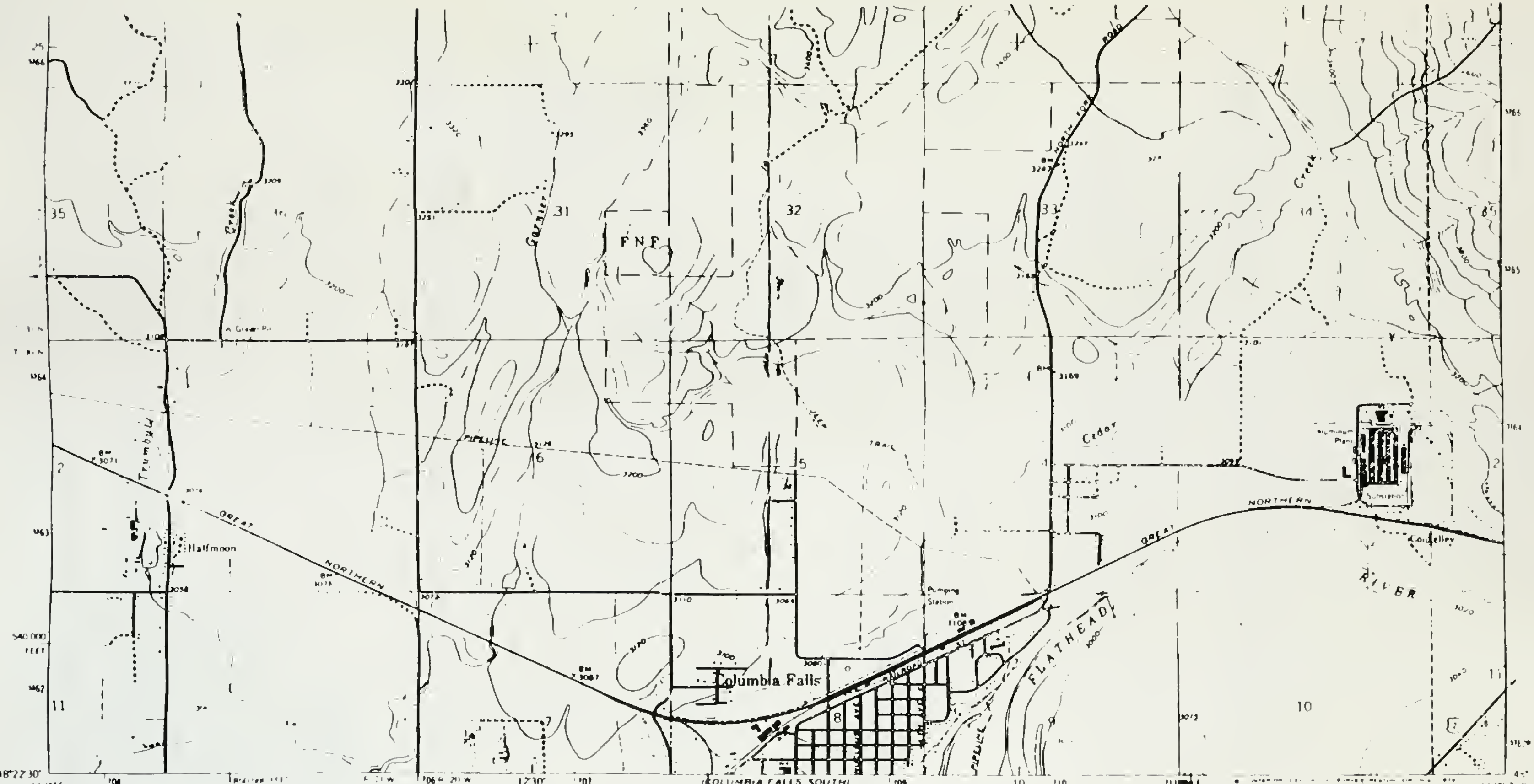

48°22'30"
114°15'
COLUMBIA FALLS SOUTH
114°07'30"

Mapped edited and published by the Geological Survey

Control by USGS and USC&GS

Topography by photogrammetric methods from aerial photographs taken 1956. Field checked 1962

Polyconic projection. 1927 North American datum
10,000-foot grid based on Montana coordinate system, north zone
1000-metre Universal Transverse Mercator grid ticks, zone 11, shown in blue

UTM GRID AND 1962 MAGNETIC NORTH DECLINATION AT CENTER OF SHEET

SCALE 1:24 000

CONTOUR INTERVAL 40 FEET
DOTTED LINES REPRESENT 20-FOOT CONTOURS
NATIONAL GEODETIC VERTICAL DATUM OF 1929

THIS MAP COMPLIES WITH NATIONAL MAP ACCURACY STANDARDS
FOR SALE BY U S GEOLOGICAL SURVEY DENVER COLORADO 80225 OR RESTON VIRGINIA 22092
A FOLDER DESCRIBING TOPOGRAPHIC MAPS AND SYMBOLS IS AVAILABLE ON REQUEST

MONTANA

QUADRANGLE LOCATION

ROAD CLASSIFICATION

Medium duty — Light duty

Unimproved dirt

U.S. Route

COLUMBIA FALLS NORTH, MONT

1962

Distribution Route Description

The powerline now serving the Cedar Creek Dam Chlorination Building originates at the Columbia Falls Substation located south of the Great Northern Railroad and 12th Avenue West intersection in the City of Columbia Falls. At this point, the feeder is a three-phase, 12.5 kV overhead line with #4/0 ACSR phase conductors. The feeder follows 12th Avenue West north to the railroad where the conductor size is increased to 556 MCM AAC. The line follows the railroad tracks northeast for about 1800 feet where conductor size is decreased to #2/0 Copper. It then continues along the railroad northeast to Fork Road. Here, the feeder conductors change to #2 Copper and the line follows Fork Road north to Aluminum Drive. At this point, a single-phase, 7.2 kV overhead line of #4 ACSR continues north along North Fork Road. Service to the chlorination building is provided by a single-phase underground tap of #2 aluminum conductors at a point approximately 1.5 miles north of Aluminum Drive. The tap extends approximately .8 miles east to the vicinity of the dam.

FIGURE 1
CEDAR CREEK DAM RELEASE
HYDROGRAPH 1972, 1982

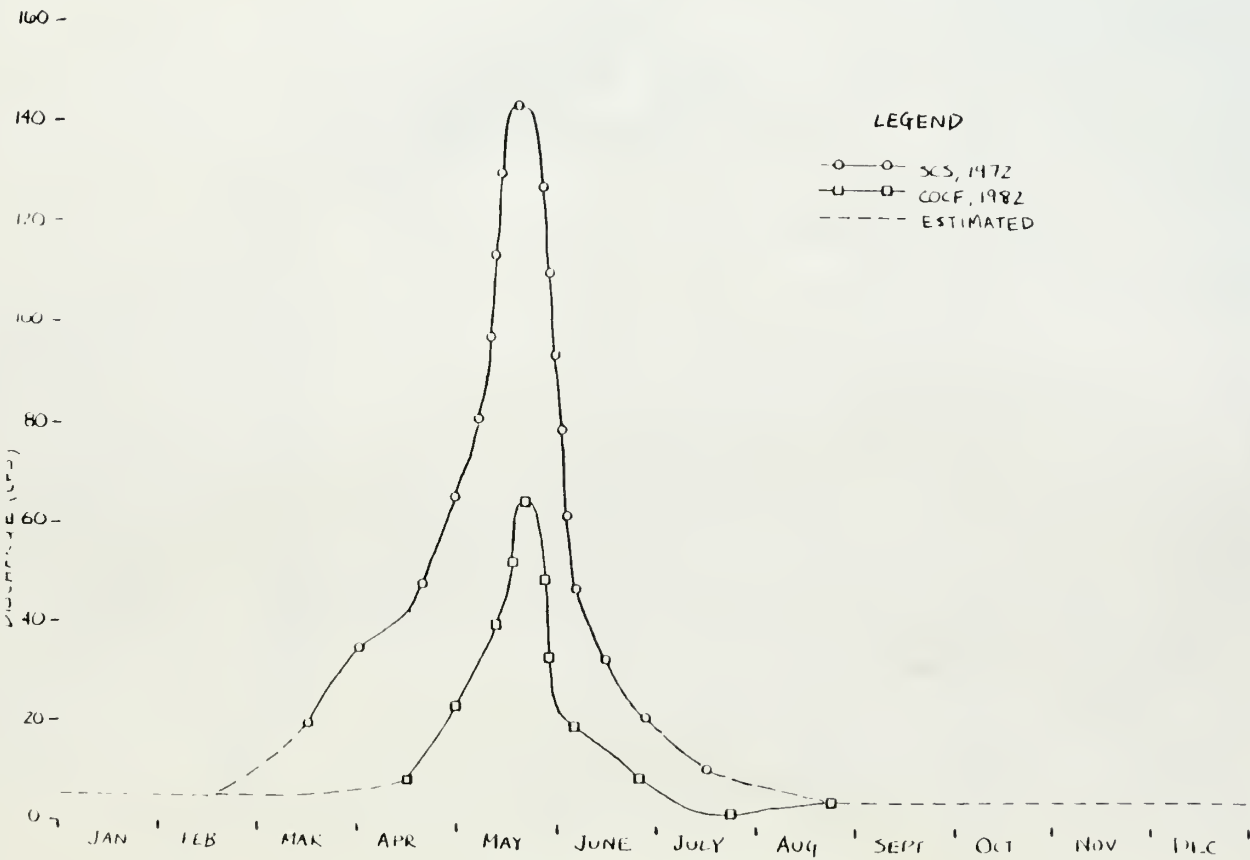

FIGURE 2 — UNIT FLOW DURATION VS. DRAINAGE AREA

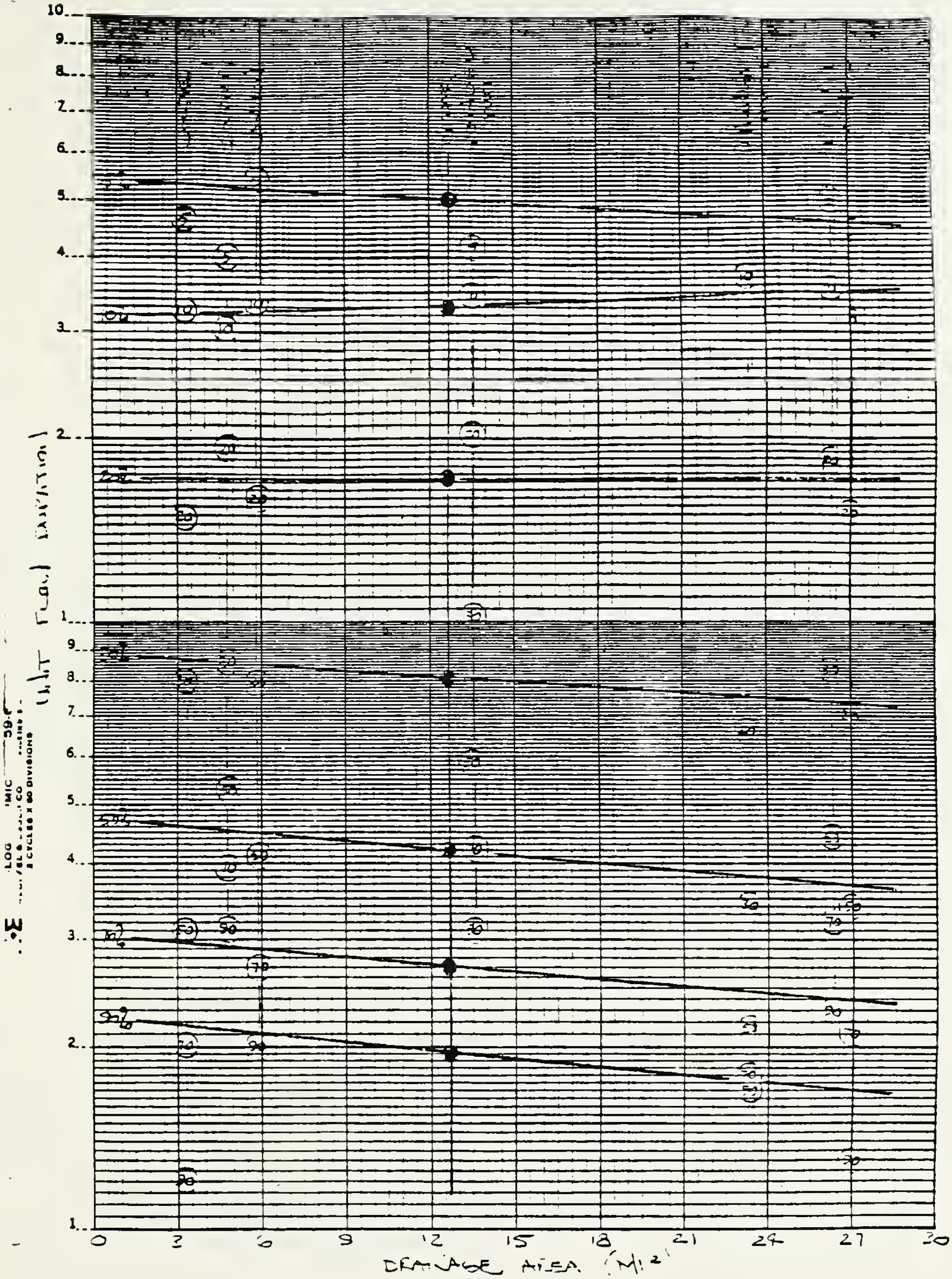

FIGURE 3
FLOW DURATION CURVE
CEDAR CREEK AT CEDAR CREEK DAM

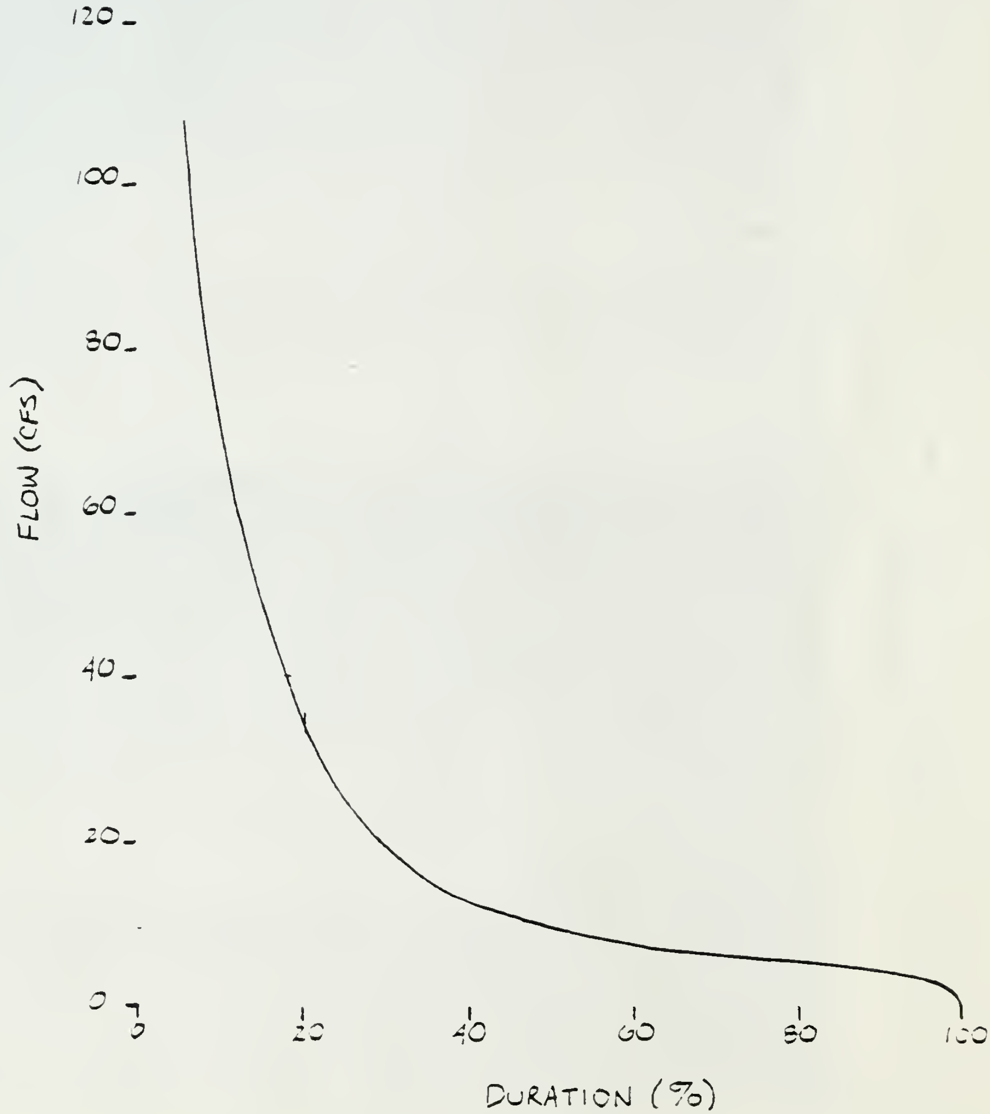

Table 1
FLOW DURATION CORRELATION ANALYSIS

Stream	Period of Record	Drainage Area (MI²)	Average Annual Flow (CFS)	5% Q (CFS)	5% Unit	10% Q (CFS)	10% Unit	20% Q (CFS)	20% Unit	30% Q (CFS)	30% Unit	50% Q (CFS)	50% Unit	70% Q (CFS)	70% Unit	90% Q (CFS)	90% Unit
				Actual and Unitized Flows — Exceedance Percentage													
Goldie Creek	1965-1966	3.29	10.5	48.8	4.65	34	3.29	15.6	1.49	8.4	0.8	3.3	0.31	2.1	0.2	1.3	0.12
Sollitter Creek	1965-1966	4.77	11.0	44.4	4.0	33.7	3.06	21.2	1.93	9.5	0.86	5.8	0.53	4.3	0.39	3.4	0.31
Canyon Creek	1965-1966	5.8	9.83	54	5.49	33	3.36	15.6	1.59	7.8	0.79	4.0	0.41	2.7	0.27	[illegible]	0.2
Bounded Buck Creek	1965-1966	13.6	69.8	292	4.18	240	3.44	141	2.02	71	1.07	41.2	0.59	29.3	0.42	21.9	0.31
Hungry Horse Creek	1970	23.1	46.8	280	5.98	174	3.72	31	0.66	16	0.34	10	0.21	8.5	0.18	7.9	0.17
Emery Creek	1965-1966	26.4	27.4	137	5.0	97.9	3.57	50.7	1.85	22.7	0.81	12	0.44	8.8	0.32	6.3	0.23
Graves Creek	1949-1967	27	135	614	4.55	422	3.13	202	1.50	95	0.70	45.7	0.34	27.8	0.21	17.3	0.13
Cedar Creek (Estimated From Figure 2)		12.7	21.6	108	5.0	71.3	3.3	37.2	1.72	17.5	0.81	9.1	0.42	5.8	0.27	4.2	0.19

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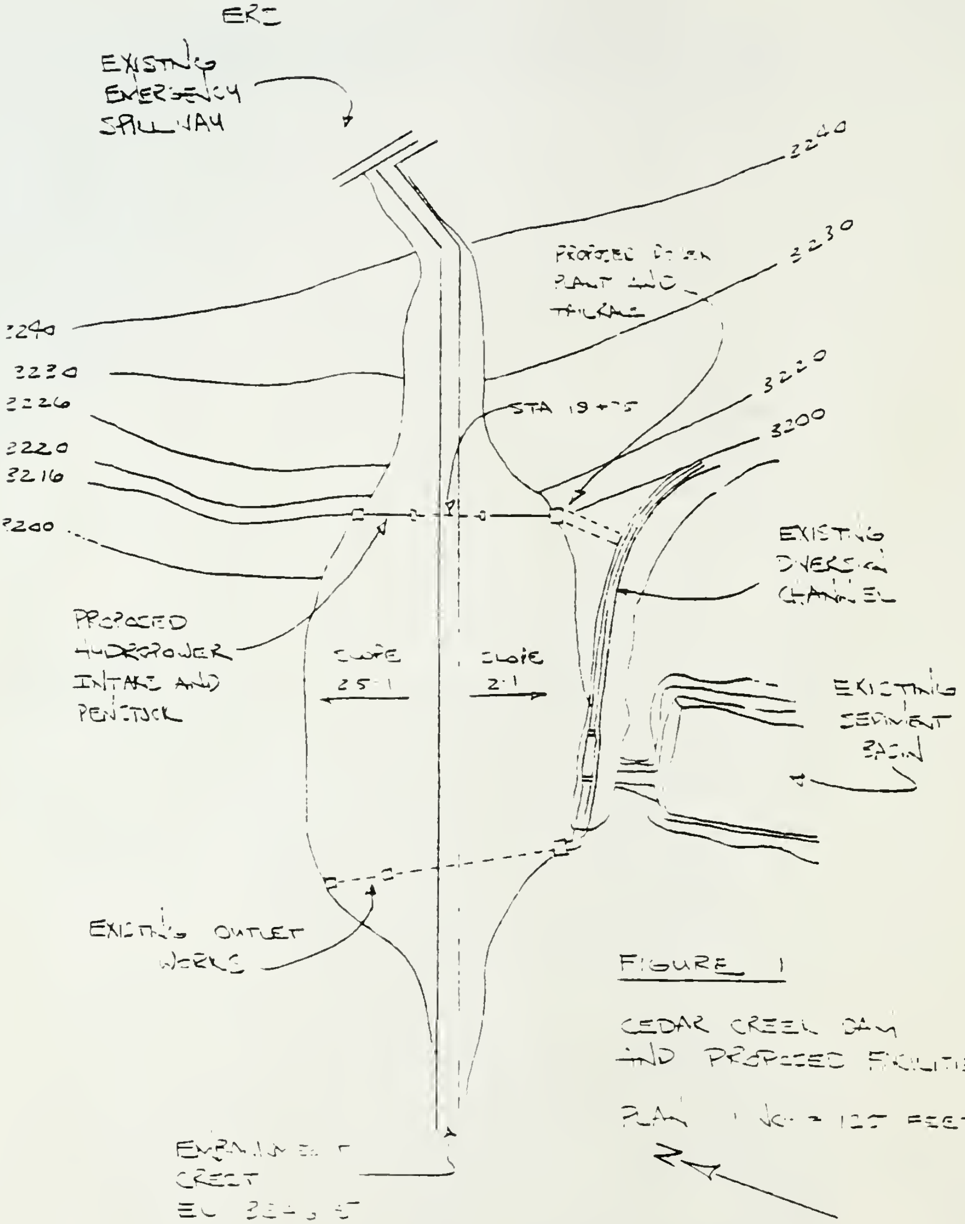


FIGURE 1

CEDAR CREEK DAM AND PROPOSED FACILITIES

PLAN 1 INCH = 120 FEET

CH2M HILL

SUBJECT ______ BY ______ DATE ______
SHEET NO ____ OF ____
PROJECT NO ______

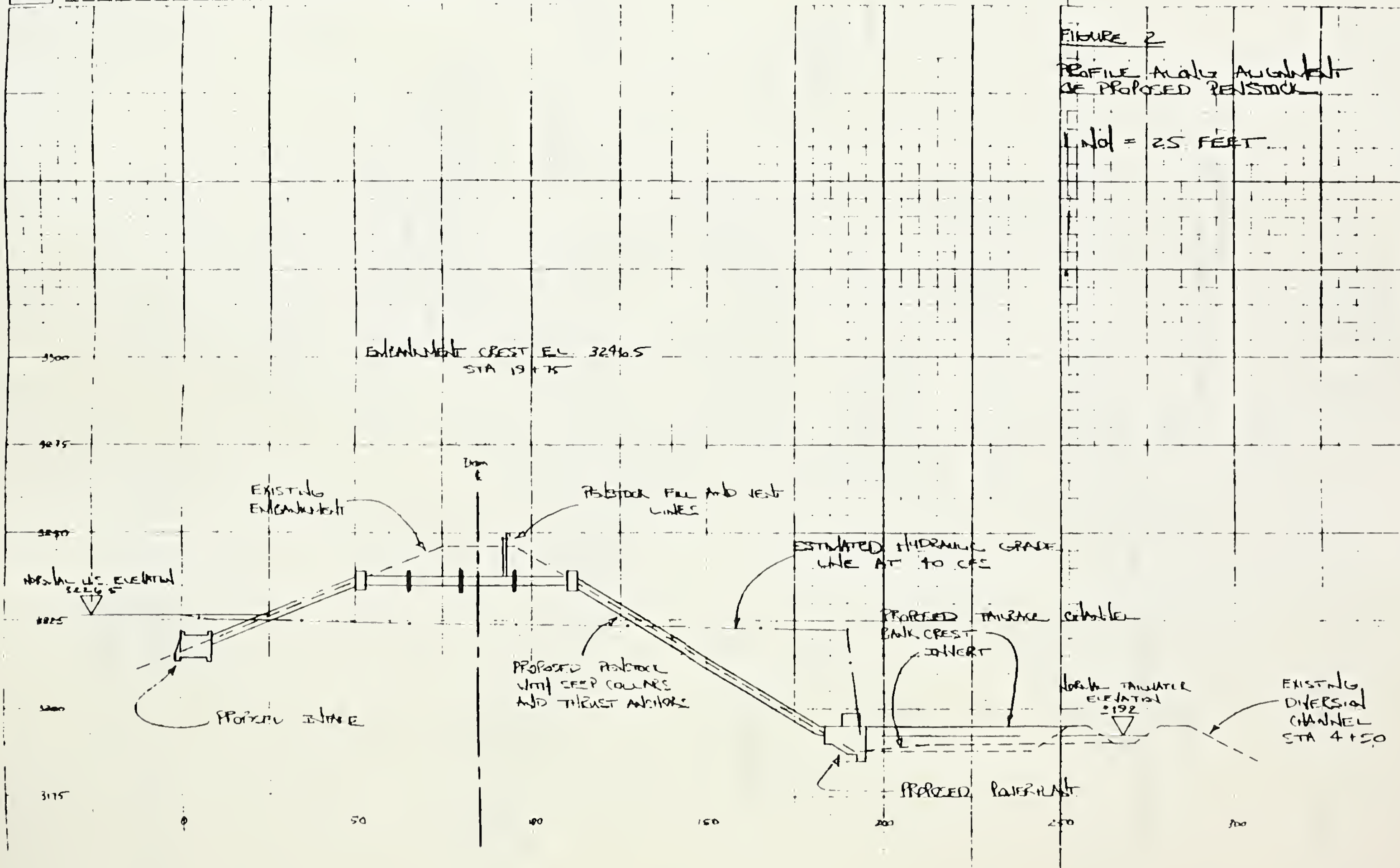
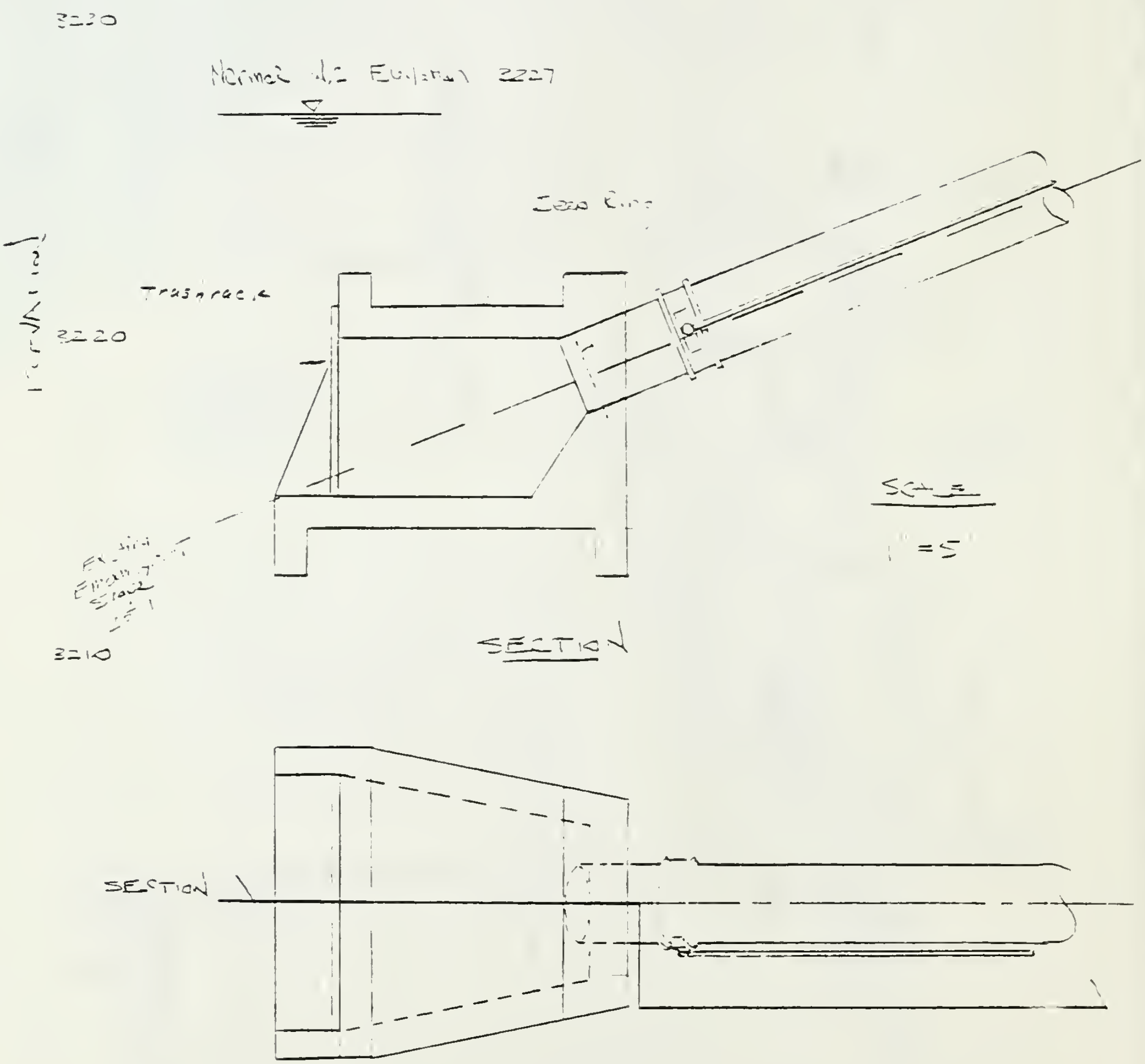


FIGURE 2

PROFILE ALONG ALIGNMENT OF PROPOSED PENSTOCK

FIGURE 3

PROPOSED SIPHON INTAKE



PLAN

$K_{trashrack} \simeq 1.0$ (50% net area, maximum velocity = 2 fps)

$K_{entrance} \simeq 1.0$

FIGURE 4

NET HEAD, HEAD LOSS, AND TAILWATER CURVES

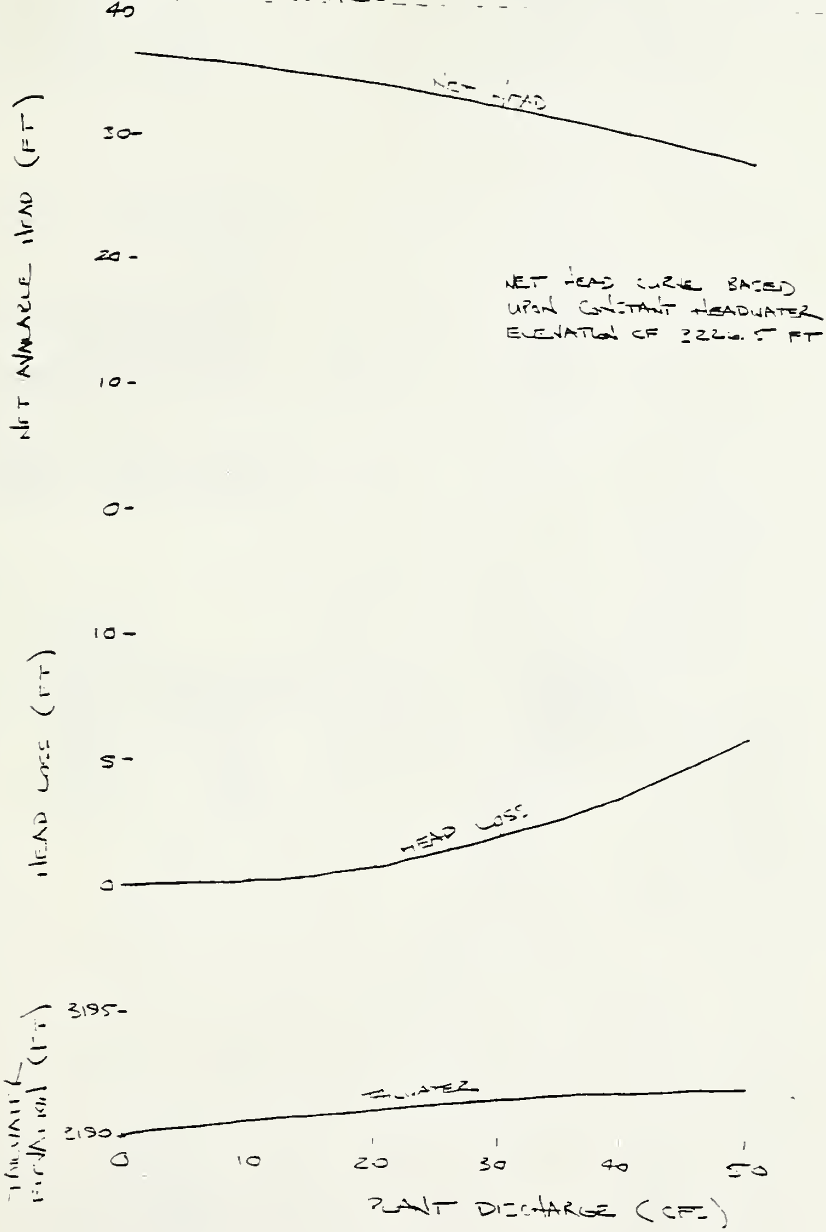
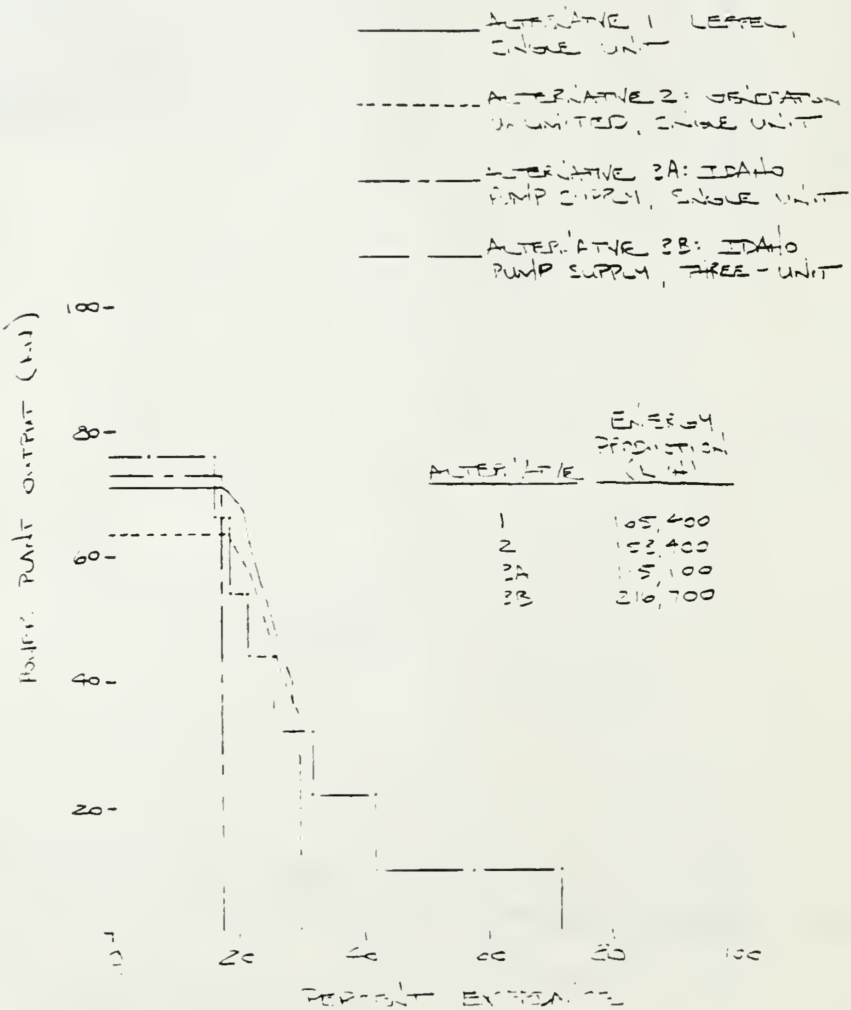


FIGURE 5
POWER DURATION CURVES



ALTERNATIVE	ENERGY PRODUCTION (KWH)
1	105,400
2	153,400
3A	115,100
3B	216,700

Table 1
COMPARISON OF EQUIPMENT PROPOSALS

Alternative	1	2	3A	3B
Manufacturer/Supplier	Leffel	Generation Unlimited	Idaho Pump Supply	
Package Cost (Synchronous)	$91,450			
(Induction)	80,000[a]	$85,000[a]	$40,000	$70,000
Delivery Time (ARO)	8-10 months	8 months	12 weeks	
Shipping	Included	Extra	Extra	
Turbine				
Number of Units	1	1	1	3
Type	Vertical Francis	Propeller	Propeller	
Rated Output	106 hp			
Rated Head	31 feet	31 feet	31 feet	
Discharge	20-38 cfs	19-37 cfs	40 cfs	6,12,24 cfs
Speed	518 rpm			
Peak Efficiency	85%			
Generator				
Type	Synchronous or Induction	Induction	Induction	
Rated Output	71 kW	68 kW	73 kW	10,22,44 kW
Voltage	480/277V, 3-phase	480/277V, 3-phase	480/277V, 3-phase	
Speed	3600 rpm			
Generator/Speed Increaser Efficiency	90%[a]			
Overall Peak Efficiency	77%	70%	70%	65,70,70%

[a]Estimated on the basis of discussions with manufacturer/supplier.

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Table 2
POWER DURATION ANALYSIS

			Efficiency, Output (%, kW)			
		Net	Alternative			
% Duration	Discharge (cfs)	Head (ft)	1	2	3A	3B
5	120					
10	72					
17	42	31				70, 76
18	40	31			70, 73	
18.5	38	31.1	71, 71			
19	37	31.2	72, 70.3	65, 63.5		70, 66
20	35	31.5	74, 69	66, 61.6		
21.5	32	32.3	77, 67.3	67, 58.6		
22	30	32.6	75, 62.1	70, 57.9		70, 54
25	26	33.3	72, 52.7	66, 48.3		
26	24	33.6				70, 44
29	20	34.3	68, 39.5	64, 37.1		
30	19	34.5		62, 34.4		
32	13	34.7				70, 32
42	12	35.4				70, 22
72	6	36				65, 10

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Table 3
SUMMARY AND COMPARISON OF ESTIMATED PROJECT COSTS
(April 1983 Level)

Item	Alternative 1	Alternative 2	Alternative 3A	Alternative 3B
1. Siphon Intake				
15 cu yd @ $300/cu yd	$ 4,500	$ 4,500	$ 4,500	$ 4,500
Trashrack, pipe extension and miscellaneous	2,000	2,000	2,000	2,000
2. Penstock (30-inch steel)				
130 feet exposed @ $125/ft	16,250	16,250	16,250	16,250
60 feet buried @ $125/ft	7,500	7,500	7,500	7,500
Upstream isolation valve with operator and miscellaneous	10,000	10,000	10,000	10,000
3. Power Plant Equipment	80,000	85,000	40,000	70,000
Installation	15,000	15,000	5,000	10,000
4. Powerhouse	10,000	10,000	10,000	15,000
5. Transmission Facilities	65,000	65,000	65,000	65,000
Subtotal	$210,250	$215,250	$160,250	$200,250
Contingency	30,000	30,000	30,000	30,000
1983 Construction Cost	$240,250	$245,250	$190,250	$230,250
Engineering and Administration	60,100	61,300	47,600	57,600
1983 Total Project Cost	$300,350	$306,550	$237,850	$287,850
Annual Costs:				
Amortization @ 10% for 30 years	$ 31,870	$ 32,530	$ 25,240	$ 30,540
Operation and Maintenance	5,000	5,000	7,000	10,000
Total	$ 36,870	$ 37,530	$ 32,240	$ 40,540
nnual Energy Production (kWh)	165,400	153,400	115,100	216,700
ergy Cost (mills/kWh)	223	245	280	187

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